September 17, 1998

EA-98-440

Mr. Walter G. MacFarland IV
Senior Vice President
Clinton Power Station
Illinois Power Company
Mail Code V-275
P. O. Box 678
Clinton, IL 61727

SUBJECT: CLINTON INSPECTION REPORT 50-461/98014(DRP) AND NOTICE OF ENFORCEMENT DISCRETION

Dear Mr. MacFarland:

On August 18, 1998, the NRC completed an inspection at your Clinton facility. The enclosed report presents the results of that inspection.

During the period covered by this inspection, the conduct of activities at Clinton Power Station was generally characterized by safety-conscious operations, sound maintenance practices, and careful radiological work controls. We are concerned, however, about one violation of NRC requirements that was identified pertaining to the operability of the Division III Emergency Diesel Generator (EDG). Specifically, NRC inspectors identified that Technical Specification requirements were not met because the Division III EDG cannot automatically switch during surveillance testing from the test (droop) mode to the isochronous mode as required in response to an actual or simulated emergency core cooling system initiation signal. This item is of concern because the Division III EDG test conditions were such that the high pressure core spray (HPCS) pump, which is powered by Division III, would not have been able to supply the required flow to the core if a valid HPCS signal was received while the EDG was being tested. Also of concern is that your staff did not recognize that the design of the EDG resulted in the inability to meet a Technical Specification requirement.

However, I have been authorized, after consultation with the Director, Office of Enforcement, and the Acting Regional Administrator, to exercise enforcement discretion for this Severity Level IV violation in accordance with Section VII.B.2, "Violations Identified During Extended Shutdowns or Work Stoppages," of the "General Statement of Policy and Procedures for NRC Enforcement Actions" (Enforcement Policy), and not issue a Notice of Violation in this case. The decision to apply enforcement discretion was based on consideration of the following: (1) significant NRC enforcement action has already been taken against the Illinois Power Company for the failure to comply with TS requirements; (2) additional enforcement action is not considered to be necessary to achieve remedial action for the violation due to Clinton

Power Station's commitments in its Plan for Excellence to take actions to address Technical Specification compliance and operator performance issues prior to plant restart; (3) the violation is related to a problem which was present prior to the events leading to the shutdown; (4) the violation is not classified at a Severity Level I; and (5) the violation was not willful. Effective corrective actions for the violation will need to be demonstrated prior to restart.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and the enclosure will be placed in the NRC Public Document Room.

Sincerely,

Original signed by

Marc L. Dapas, Deputy Director
Division of Reactor Projects

Docket No.: 50-461
License No.: NPF-62

Enclosure: Inspection Report 50-461/98014(DRP)

cc w/encl: G. Hunger, Station Manager
R. Phares, Manager, Nuclear Safety
and Performance Improvement
J. Sipek, Director - Licensing
N. Schloss, Economist
Office of the Attorney General
G. Stramback, Regulatory Licensing
Services Project Manager
General Electric Company
Chairman, DeWitt County Board
State Liaison Officer
Chairman, Illinois Commerce Commission

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See Previous Concurrences

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REGION III

Docket No:	50-461
License No:	NPF-62
Report No:	50-461/98014(DRP)
Licensee:	Illinois Power Company
Facility:	Clinton Power Station
Location:	Route 54 West Clinton, IL 61727
Dates:	July 7 - August 18, 1998
Inspectors:	T. W. Pruett, Senior Resident Inspector K. K. Stoedter, Resident Inspector C. E. Brown, Resident Inspector D. E. Zemel, Illinois Department of Nuclear Safety
Approved by:	Thomas J. Kozak, Chief Reactor Projects Branch 4

EXECUTIVE SUMMARY

Clinton Power Station
NRC Inspection Report 50-461/98014(DRP)

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection.

Operations

- The inspectors noted that operator performance improved with respect to questioning degraded or suspect indications, taking conservative immediate actions, and initiating the appropriate corrective action document. The performance improvement was due, in part, to implementation of the operations department event free performance initiative (Section O1.1).

- The inspectors determined that the licensee's Generic Letter 91-18 program for operability determinations (ODs) was not effective in ensuring ODs were dispositioned in a timely manner. Specifically, 28 of 41 active ODs describing nonconforming conditions were older than 6 months. Actions taken in May 1998 to disposition the active ODs were not successful in that only one of five shift managers had completed the review of assigned ODs by August 1, 1998 (Section O2.1).

- Operations personnel implemented nonconservative compensatory measures for a potential fault condition affecting the Division I Nuclear System Protection System (NSPS) inverter. Specifically, operations personnel viewed declaring a faulted component administratively inoperable as an adequate compensatory measure even though leaving the faulted NSPS inverter energized could potentially introduce complications with the power supply (Section O2.2).

- Operations personnel did not recognize a potential reduction in ultimate heat sink inventory as a condition requiring an OD or mode restraint (Section O2.3).

- As a result of the corrective actions that were implemented to improve performance in the safety tagout program, including providing additional staffing, increasing management oversight, and improving training for operations and maintenance personnel, tagout events were reduced from 11 in 1997 to 3 as of August 1, 1998 (Section O2.4).

- The inspectors' review of the operations department self-assessment program revealed that, between January and July 1998, it did not have a stable program owner to oversee completion of self-assessments, weaknesses identified in operator radiation work practices were not addressed, and recommendations and weaknesses described in the radiation worker practice and quarterly assessment reports were not tracked or assigned a responsible owner. These findings were indicative of the need for improvement in the operations department's formal self-assessment program (Section O7.1).

Maintenance

- C The inspectors concluded that the licensee's revised molded case circuit breaker testing program conformed to the latest NRC and industry guidance (Section M1.2).

- C Although the Division II emergency core cooling system (ECCS) integrated loss-of-offsite-power and loss-of-coolant-accident surveillance testing was completed without complications, the preplanning for the test could have been more thorough. For example, some personnel assignments were initially made and/or changed at the briefing, communication links were not established ahead of time, the placement of test cables created a tripping hazard, mechanical stops were not used on open cabinets, and test switches were installed inside energized panels. Additionally, the prejob brief did not include lessons learned, industry experience, or contingencies (Section M1.3).

- C The inspectors noted that management expectations were not met during the review of selected condition reports (CRs) in that maintenance personnel did not determine and document the extent of the condition associated with some level three CRs (Section M7.1).

- C The inspectors identified a weakness with the scheduling and completion of Technical Specification Surveillance Requirements (SRs). The identified issues included: 44 percent of all monthly and quarterly surveillances were being performed in the 25 percent grace period after the due date; 11 overdue Technical Specification SRs were omitted from a weekly surveillance test report; personnel were unaware of the safety-related preventive maintenance (PM) tasks that were required to meet a specific Technical Specification SR; and, the impact on Technical Specification SRs was not evaluated for a late safety-related PM task (Section M8.1).

Engineering

- C Engineering personnel did not provide adequate support to operations personnel in that a CR addressing an already resolved issue was not closed in a timely manner (Section O2.2).

- C One violation was identified for which enforcement discretion was exercised. The inspectors identified that Technical Specification requirements were not met because the Division III EDG cannot automatically switch during surveillance testing from the test (droop) mode to the isochronous mode as required in response to an actual or simulated emergency core cooling system initiation signal. This item is of concern because the Division III EDG test conditions were such that the high pressure core spray (HPCS) pump, which is powered by Division III, would not have been able to supply the required flow to the core if a valid HPCS signal was received while the EDG was being tested. Also of concern is that the licensee did not recognize that the design of the EDG resulted in the inability to meet a Technical Specification requirement (Section E8.6).

Plant Support

- C The licensee's self contained breathing apparatus inspection program was thorough in that inspections were performed at the proper frequency, all material condition and functionality issues were addressed, and appropriate actions were taken when test failures were identified (Section R1.1).

- C In preparation for the installation of a fire separation wall, the licensee removed a 2-inch suppression pool cleanup line which resulted in an estimated 28 person-rem dose savings for the modification. This demonstrated effective implementation of the As Low As Reasonably Achievable (ALARA) program (Section R1.2).

- C The inspectors determined that emergency planning personnel had not verified the capability to staff emergency response organization positions following a failure of the autodialer pager system even though there had been four failures of the pager system since July 1997 (Section P1.1).

Report Details

Summary of Plant Status

The facility remained shutdown during the inspection period. Major maintenance activities included installation and testing of the emergency reserve auxiliary transformer (ERAT) modification. The ERAT modification was implemented to improve the reliability of the 138 kV offsite power source.

I. Operations

01 Conduct of Operations

O1.1 Improved Awareness of Plant Conditions

a. Inspection Scope (71707)

The inspectors reviewed operator response to various plant conditions.

b. Observations and Findings

Degraded Fuel Pool Cooling (FC) Pump

In February 1998, engineering personnel initiated Condition Report (CR) 1-98-02-228 to document an issue involving the set point for component cooling water flow Switch 1FIS-CC191A(B). Operations personnel determined that the reliability of the FC pumps was in question because it was not known at what level below 10 inches of water column the pumps would trip. Operations personnel determined that the pumps remained operable provided a manual operator action was taken within 5 minutes to ensure the pumps tripped following a loss of component cooling water.

On July 6, during a review of main control room deficiencies, the inspectors questioned how the FC pumps could remain operable given the limited time for manual operator action following a loss of component cooling water. Operations personnel reevaluated the issue and declared the FC pumps inoperable.

On July 7, the inspectors noted that an entry had not been made in the control room station log to annotate that the FC pumps were inoperable, even though a log entry had been made in the shift manager's log reflecting the change in FC pump status. Operations personnel updated the control room station log to correct the omission.

On July 20, operations personnel initiated CR 1-98-07-238, to document that the operability of the FC pumps had not been properly assessed in February 1998, and that no system currently existed for statusing equipment important to safety unless it had a limiting condition for operation (LCO) specified in the TS, operational requirements manual (ORM), or off-site dose calculation manual (ODCM). The inspectors noted that the change in the operational classification of the FC pumps and the initiation of the CR regarding the program deficiency in statusing equipment important to safety, were reflective of improvement initiatives involving event free performance in the operations department.

ERAT Outage Configuration

On July 21, on shift operations personnel noted that an approved maintenance activity proposed an ERAT outage configuration which was not in accordance with the Updated Safety Analysis Report (USAR) and did not allow the activity to proceed, questioned engineering and work management personnel on the validity of the configuration, and documented the issue in CR 1-98-07-265. In response to the issue, the licensee developed an alternate method to accomplish the maintenance activity while meeting the requirements specified in the USAR.

Conservative Operator Action Following Spike in EDG Indications

On July 22, during surveillance testing, operations personnel observed a spike in the output watts and output current on the Division I EDG and immediately secured the EDG. Operations personnel declared the EDG inoperable and initiated a CR to resolve the issue.

Identification of Main Control Room Deficiencies

Between July 6 - August 10, 1998, operations personnel identified 93 new main control room deficiencies. During the same period, 71 main control room deficiencies were closed. The increased identification of suspect indications resulted in the assignment of additional control and instrumentation resources to work down the backlog of main control room deficiencies.

Control Room Station Logs

The inspectors questioned operations personnel regarding the status of corrective actions for three deficiencies described in the control room station log. Two deficiencies, an EDG ventilation fan failing to start and a station air valve failing to fully close during post maintenance testing, were appropriately documented in the station log and condition reports were initiated.

The third deficiency identified the potential for intermediate range Monitor H to "hang up" on withdrawal. Operations personnel appropriately documented the issue in the station log; however, a condition report or mode restraint was not initiated to track the discrepancy. Following discussions with the inspectors, operations personnel initiated a mode restraint and a condition report to ensure resolution of the issue.

c. Conclusions

The inspectors noted that operator performance improved with respect to questioning degraded or suspect indications, taking conservative immediate actions, and initiating the appropriate corrective action document. The performance improvement was due, in part, to implementation of the operations department event free performance initiative.

02 Operational Status of Facilities and Equipment

O2.1 Operability Determinations

a. Inspection Scope (71707 and 37551)

The inspectors performed a review of active operability determinations (ODs) using the guidance provided in Generic Letter (GL) 91-18, Revision 1, "Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions."

b. Observations and Findings

The inspectors noted that Procedure 1014.06, "Operability Determinations," was consistent with the guidance provided in GL 91-18, Revision 1. However, the inspectors noted that approximately 41 active ODs were in place as of August 1, 1998. The inspectors reviewed the active ODs to determine if safety evaluations or corrective actions had been performed when required. The inspectors noted that active ODs existed for components declared inoperable by the operations department and that for at least 15 active ODs safety evaluations had not been written to address the nonconforming conditions that were the subject of the ODs. The inspectors also noted that the nonconforming conditions described in the active ODs were not dispositioned in a timely manner. Specifically, 5 ODs were open greater than 18 months, an additional 5 ODs were open greater than 12 months, and 18 ODs were open greater than 6 months.

The operations manager informed the inspectors that a review of the OD program had been initiated as part of the Plan For Excellence in May 1998. As part of the review, ODs were divided among the five shift managers. The shift managers were tasked with determining if the ODs were ready for closure based on actions completed to date or determining the actions necessary to close each OD. On August 1, the inspectors noted that only one shift manager had determined the status of the ODs assigned for review.

Following discussions with the inspectors, operations personnel determined that 12 of the 41 ODs remained active, even though the corresponding condition report had been closed, and initiated actions to close the affected ODs. Additionally, a review of each OD was initiated to determine if a safety evaluation was required, whether or not the USAR needed to be revised to reflect the existing plant condition, and whether or not appropriate corrective actions had been taken or planned. The operations manager stated that prior to restart of the facility, nonconforming conditions described in ODs would either be corrected or an approved safety evaluation would be processed for a compensatory action or acceptance of the condition.

c. Conclusions

The inspectors determined that the licensee's GL 91-18 program for ODs was not effective in ensuring ODs were dispositioned in a timely manner. Specifically, 28 of 41 active ODs describing nonconforming conditions were older than 6 months. Actions taken in May 1998 to disposition the active ODs were not successful in that only one of five shift managers had completed the review of assigned ODs by August 1, 1998.

O2.2 Implementation of OD for Division I and II Nuclear System Protection System (NSPS) Inverters

a. Inspection Scope (71707 and 37551)

The inspectors reviewed implementation of OD 1-98-02-525 involving the placement of the Division I NSPS inverter in the maintenance bypass position.

b. Observations and Findings

Condition Report 1-98-02-525 was initiated on February 27, 1998, to document a potential fault pathway between the station ground and instrument ground when the Division I and II NSPS busses were aligned to the maintenance bypass position. The fault pathway was identified during a system design and functional validation (SDFV) review of engineering change notice (ECN) 28519, which had been initiated to make wiring changes to the NSPS inverter maintenance bypass switch.

Following initiation of CR 1-98-02-525, the originator of the CR was provided with ECN 28997, which was initiated to resolve the grounding concern created by ECN 28519. Specifically, ECN 28997, which was implemented in April 1995, modified the circuit to relocate the ground point connection for the low side windings of the regulating transformer so that the transformer would be separated from the ground point when the circuit breaker was opened. Even though the fault condition did not exist and in spite of the ECN documentation, the CR was issued.

On June 23, during a review of CRs, operations personnel noted that CR 1-98-02-525 remained open. Operations personnel initiated OD 1-98-02-525 and transferred the concerns described in CR 1-98-02-525 to OD 1-98-02-525 without requesting assistance from engineering personnel. The inspectors noted that the untimely (approximately 5 months) resolution of the CR by engineering personnel resulted in the unnecessary development and implementation of compensatory actions by operations personnel.

The CR and OD described that if there was a fault when the inverter was aligned to the bypass position, transient noise affecting plant instrumentation, inadvertent engineered safety feature (ESF) actuations, or the failure of necessary ESF equipment to actuate could occur. The compensatory measure described in the OD for aligning the NSPS inverter to the maintenance bypass position, was to declare the associated NSPS distribution system administratively inoperable and implement the required TS actions.

The inspectors noted that the Division I NSPS inverter was aligned to the maintenance bypass position on July 23 and 24. During this period, operations personnel aligned what they believed to be a faulted component to the safety-related busses creating the potential for the previously described problems to occur. The inspectors considered the compensatory measures in the OD nonconservative in that declaring the NSPS distribution system administratively inoperable did not address the potential problems associated with a faulted component.

On August 4, 1998, the licensee determined a drafting error had incorrectly specified the location of the ground on USAR Figure 8.3-2, "NSPS Power Distribution," for the Division II maintenance bypass feed, initiated corrective actions to revise the affected drawings and figures, and closed OD 1-98-02-525.

c. Conclusions

Operations personnel implemented nonconservative compensatory measures for a potential fault condition affecting the Division I NSPS inverter. Specifically, operations personnel viewed declaring a faulted component administratively inoperable as an adequate compensatory measure even though leaving the faulted NSPS inverter energized could potentially introduce complications with the power supply.

Engineering personnel did not provide adequate support to operations personnel in that a CR addressing an issue that had already been resolved was not closed in a timely manner. Consequently, operations personnel unnecessarily implemented compensatory measures for an invalid CR.

O2.3 Operational Determination for Shut Down Service Water

a. Inspection Scope (71707)

The inspectors reviewed circumstances surrounding a nonconforming condition involving a loss of inventory from the Ultimate Heat Sink (UHS) under certain accident conditions.

b. Observations and Findings

On July 10, 1998, engineering personnel initiated CR 1-98-07-130 to document that during an accident involving the loss of the Clinton Lake Main Dam, approximately 10 gpm of cooling water for the post-accident sampling system would be supplied via the shutdown service water system from the UHS, and then be rejected via the plant service water system, which does not discharge to the UHS. Updated Safety Analysis Report, Section 9.2.5.2, "Ultimate Heat Sink System Description," described the potential losses from the UHS but did not include a description of the 10 gpm supplied to the post-accident sampling system.

The inspectors discussed the issue with operations personnel on July 27 and 28. Operations personnel initially stated that since TS 3.7.1, "Division 1 and 2 Shutdown Service Water (SX) and Ultimate Heat Sink (UHS)," did not require the UHS to be operable in Mode 4, no OD was required and that resolution of the issue would be a mode restraint for startup. However, the inspectors noted that the item had not been added to the mode restraint list.

On July 29, operations personnel re-evaluated the documentation associated with the reduced UHS inventory issue, concurred with the inspectors that a nonconforming condition existed, and performed an OD to assess whether the UHS could perform its intended safety function with the additional lost inventory.

c. Conclusions

Operations personnel did not recognize a potential reduction in UHS inventory as a nonconforming condition requiring an OD or mode restraint. Following prompting by the inspectors, operations personnel initiated an OD to assess whether the UHS was capable of performing its intended safety function during accident conditions.

O2.4 Tagout Program Implementation

a. Inspection Scope (71707)

The inspectors reviewed the tagout program to determine the effectiveness of changes made to the program.

b. Observations and Findings

CPS Safety Tagging Program

On July 22, 1998, the inspectors noted what appeared to be an increasing trend in the number of tagging related errors. The inspectors attended a condition review group (CRG) meeting associated with a tagging related error and noted that the licensee did not discuss or identify an emerging trend associated with tagouts. The corrective action group manager stated that the CRG was not chartered to identify trends involving CRs and that each department had the responsibility to identify emerging and adverse trends during the CR review (see Section M7.1).

The inspectors noted that the licensee had initiated 17 CRs describing various tagging related deficiencies since January 1998, 9 of which were initiated between July 1 and August 10. A tagging error was defined as a tagout situation which compromised a barrier's effectiveness. Examples of tagging related errors occurring in July and August of 1998 included: four examples of not signing or initialing tagging sheets, three examples of not performing voltage checks on 480 Vac molded case circuit breakers, using an incorrect revision to a tagging sheet, and hanging a caution tag on the wrong switch. Additionally, CR 1-98-07-181 was initiated on July 15 to document the failure to perform safety evaluations for active tagouts greater than 6 months old and CR 1-98-07-358 was initiated on July 30 to document an increase in dislodged tags.

Following inspector discussions with operations personnel, a lower threshold for initiation of a tagging program review was established. The use of the lower tagging error threshold resulted in operations personnel initiating a review of the tagging program.

In spite of the recent increase in tagging errors, the inspectors noted that the number of tagging events, a situation where work was authorized to proceed without an adequate tagout, had substantially decreased in 1998. In 1997 there were 11 tagging events and 33 tagging errors. As of August 1, 1998, there have been 3 tagging events and 14 tagging errors. The inspectors attributed the reduction in tagout related deficiencies to corrective actions involving a complete revision to the tagging procedure, increased training of operations and maintenance personnel, additional verification of tagout adequacy by personnel signing a tagout, increased staffing of the tagout group, an increased lead time for tagout requests from 1 day to 2 weeks, and increased oversight of tagging issues by licensee management.

Illinois Power Dispatch Safety Tags

On July 31, the inspectors observed the relocation of the ERAT transfer switch as part of the ERAT modification. During the transfer, a CPS site safety department representative found a dislodged Illinois Power dispatcher safety tag and gave the tag to the CPS project manager. The project manager realized where the tag was supposed to be placed and reinstalled the tag on the disconnect switch ratchet mechanism.

The inspectors questioned the two CPS individuals about the appropriateness of reinstalling the safety tag without operations department assistance. The project manager requested the assistance of the project engineer (an Illinois Power employee working out of the corporate dispatch office), who stated that the safety tag was controlled by corporate procedures, that notifying CPS operations personnel per the site procedure was not required, and that it is common practice for personnel in his position to manipulate safety tagged equipment as necessary to complete assigned tasks.

The inspectors questioned the operations manager on the control of dispatcher safety tags. The operations manager stated that it was his expectation that the main control room be knowledgeable of occurrences involving safety tags and that the activity would be used as a learning experience, and ensured that a CR was initiated to document the event.

The inspectors reviewed Procedure 1014.01, "Safety Tagging Procedure," and noted that the CPS site specific procedure made reference to Corporate Procedure EO 3.14, "Transmission and Sub-Transmission Systems, Electric System Switching" for dispatcher tagging. The inspectors noted that Procedure EO 3.14 did not provide guidance on the reinstallation of dislodged safety tags. Additionally, Procedure EO 3.14 provided minimal guidance on when notification should be made to CPS operations personnel during the installation and removal of safety tags by dispatcher personnel. The licensee stated that a review of procedures providing guidance on the installation and removal of dispatcher safety tags would be performed.

c. Conclusions

As a result of the corrective actions that were implemented to improve performance in the safety tagout program, including providing additional staffing, increasing management oversight, and improving training for operations and maintenance personnel, tagout events were reduced from 11 in 1997 to 3 as of August 1, 1998. However, the authorization for corporate dispatch personnel to hang and remove safety tags without notifying control room personnel did not meet operations management's expectations.

07 Quality Assurance in Operations

O7.1 Operations Department Self-assessments

a. Inspection Scope (71707)

The inspectors reviewed operations department self-assessments completed between January and July 1998.

b. Observations and Findings

Self-assessment Schedule

The latest schedule for operations formal and informal self-assessments was approved on September 30, 1997, by the former operations manager and did not reflect current or planned self-assessment activities. In response to the inspectors' observation, operations personnel formulated a new self-assessment schedule on August 5, 1998, which included restart readiness reviews, plan for excellence action reviews, and program effectiveness reviews in response to identified deficiencies in risk management and safety tagging. The new schedule did not include ongoing informal self-assessment activities.

The inspectors noted that several restart readiness reviews were in progress but that only one formal self-assessment (radiation worker practices) had been completed in the operations department between January 1 and July 31, 1998. Informal assessments performed by operations personnel included the ongoing safety tagging monitoring program and the station operations monitoring program. Participation in the station operations monitoring program had decreased due to development and implementation of the operations department event free performance initiative. As noted in Section 01.1 of this report, the event free performance initiative has increased operator awareness of suspect plant indications.

The inspectors noted that four formal self-assessments specified on the September 1997 schedule were assigned to individuals no longer in the operations department.

Operations personnel stated that the affected assessments had been incorporated into the Plan For Excellence schedule.

Operations personnel stated that the schedule had not been updated, in part, due to turnover in the operations department self-assessment coordinator position. Since January 1998, four individuals have been selected as the self-assessment coordinator. The frequent turnover resulted in reduced oversight of program implementation.

Radiation Worker Practices Self Assessment

The inspectors reviewed operations department self-assessment OPS-98-064, dated April 27, 1998. The assessment was initiated in response to an adverse trend associated with operator radiation work practices. The inspectors noted that the assessment did not use personnel assigned to the radiation protection department to assist in the review and that the evaluation guide did not assess the use of survey instruments by operations personnel.

The discussion section of the assessment described a weakness involving posted surveys. Based on the assessment, the licensee determined that most operations personnel were unaware that the surveys did not include the weekly reference point survey data. However, no corrective actions, recommendations, or CRs were initiated to resolve the weakness.

Three recommendations were made regarding placement of exit terminals, purchase of shoe covers, and a semi-annual performance of an operations department radiation worker practices self-assessment. The inspectors questioned operations personnel to determine how recommendations and weaknesses documented in self-assessment reports were tracked and resolved. Operations personnel stated that items identified in the radiation worker practice self-assessment and the operations department quarterly report had not been placed in a tracking system or assigned to a responsible individual for resolution.

The inspectors noted that CR 1-98-06-246 was initiated on June 19, 1998, to document the failure of operations personnel to track recommendations documented in the late 1997 "Utilization of Operations Resources," formal self-assessment. In response to the CR, operations personnel determined that the recommendations were tracked via the Plan For Excellence. However, a review to determine whether or not other self-assessments were similarly affected was not performed. Consequently, the licensee missed an opportunity to identify the failure to track weaknesses documented in other operations department self-assessments.

The inspectors noted that the licensee's failure to implement corrective actions for deficiencies identified in self-assessments was the subject of an NRC Notice of Violation (50-461/98008-05, issued June 25, 1998) for which enforcement discretion was exercised in accordance with Section VII.B.2 of the enforcement policy. The inspectors noted that the licensee's corrective actions for this violation had not been fully implemented at the end of the inspection period. This violation constitutes an additional example of NCV 50-46198005-05 and is not being cited individually. Further corrective actions for this additional example are expected to be taken in conjunction with corrective actions for the previous violation.

In response to the observations, the licensee stated that the radiation worker performance assessment would be re-performed. However, when the new self-assessment schedule was approved in August 1998, it did not include a radiation worker practices self-assessment.

c. Conclusions

The formal operations department self-assessment program did not have a stable program owner to oversee completion of self-assessments, weaknesses identified in the radiation worker practice assessment were not corrected, and recommendations and weaknesses described in the radiation worker practice and quarterly assessment reports were not tracked or assigned a responsible owner.

08 Miscellaneous Operations Issues (92700 and 92901)

O8.1 (Closed) Notice of Violation 50-461/96412-06: Failure to notify chemistry personnel of a reduction in power so that a gaseous sample could be obtained. This item was originally described in NRC Inspection Report 50-461/96010. Initial corrective actions involved, in part, development of a management observation program to improve supervisory oversight, training on procedural compliance, and discussions of when chemistry samples are required. Subsequent to the violation response, the licensee has initiated several human performance improvement initiatives described in the Plan For Excellence.

O8.2 (Closed) Notice of Violation 50-461/96412-10: Failure of the shift technical advisor (STA) to assist the shift supervisor during an Unusual Event. This item was previously described in NRC Inspection Report 50-461/96010. In response to this violation, the licensee counseled the STA on required duties and adherence to procedures. In addition, the licensee conducted expectations training and seminars addressing this issue, similar human performance errors, procedure adherence, and conservative decision making. Inspection Report 50-461/98009 identified that an STA performed the initial off-site notifications during an event when a non-licensed operator was unable to accomplish the actions. The inspectors planned to review the licensee’s revised corrective actions for this issue as part of the closeout activities for Inspection Follow-up Item 50-461/98009-01.

O8.3 (Closed) Notice of Violation 50-461/97022-01and Inspection Follow-Up Item 50-461/97999-14: Two examples of the failure to implement the required actions of TSs. In the first example, operations personnel failed to verify the availability of an alternate method of decay heat removal every 24 hours in that a requirement to verify the proper alignment of the component cooling water system did not exist. Consequently, component cooling water flow was aligned to a heat exchanger that was not in service for alternate decay heat removal. The licensee's corrective actions involved proper alignment of component cooling water following the initial discovery, defining the meaning of "available," and a revision to Procedure 3303.01, "Reactor

Water Cleanup," to include verification of component cooling water system valve positions when using the reactor water cleanup system as an alternate source of decay heat removal.

In the second example, operations personnel failed to ensure immediate actions were pursued to restore the electrical distribution system. Corrective actions included a re-emphasis on continuously working maintenance items which implement immediate actions required by the TS, clarification of the application of immediate actions, and improvements in the work management processes. Following the identification of the violation in September 1997, the inspectors have observed an increased awareness of TS required immediate actions by licensee personnel.

O8.4 (Closed) Licensee Event Report (LER) 50-461/97-030: Failure to verify the reactor water cleanup system was available as an alternate means of shutdown cooling. The onsite review of this LER was performed during the inspectors review of corrective actions in response to Violation 50-461/97022-01 (see Section O8.3).

O8.5 (Closed) Inspection Follow-up Item 50-461/97999-10: Heavy reliance on the use of standing orders. This item was initially identified during the NRC Special Evaluation Team (SET) review performed between September - December 1997. The concern involved the use of standing orders in lieu of plant procedures. The licensee initiated a review with the objective of incorporating all existing standing orders into an approved procedure and re-emphasized that standing orders were to be issued for short durations. The licensee's actions for this item were appropriate.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (61726 and 62707)

Portions of the following maintenance and surveillance activities were observed or reviewed by the inspectors:

Procedure 8199.01	Concrete Expansion Anchor Work
Procedure 8410.04	Molded Case Circuit Breaker Functional Testing and Maintenance
Procedure 9080.01	Diesel Generator 1A(B) Operability - Manual and Quick Start Operability
Procedure 9080.22	Diesel Generator 1B - ECCS Integrated Testing
Procedure 9382.18	Division III 125VDC Battery Capacity Test
MWR D82288	Replace and Reroute Line 1SF028A - 2 Inch Line

The inspectors noted that observed activities were performed with the procedure present and in active use. Technicians were knowledgeable of the task and used calibrated test equipment. Further observations by the inspectors are described in Sections M1.2 and M1.3 below.

M1.2 MCCB Testing Program

a. Inspection Scope (62707 and 61726)

The inspectors reviewed the licensee's revised MCCB test program.

b. Observations and Findings

The licensee issued a complete revision to Procedure 8410.04, "Molded Case Circuit Breaker Functional Testing and Maintenance," on August 7, 1998, and procured new test equipment in response to a violation for the failure to establish a test program to ensure 480-Vac MCCBs will perform satisfactorily in service (NCV 50-461/98011-06). The inspectors confirmed that Procedure 8410.04, Revision 11, and the vendors test equipment manual met the latest industry guidance with the exception that a single wire size is not specified for each breaker rating. The electrical maintenance manager stated that a "minimum" wire size had been retained in the procedure because the new test equipment would not supply enough current to the MCCB when the industry recommended wire size was used. The licensee determined that the time for a breaker trip would be longer with a larger wire size; therefore, if a breaker met the acceptable trip times with a larger wire, it would pass with the smaller industry specified wire size.

The licensee completely revised the MCCB testing method and Procedure 8410.04 was expanded to include testing the MCCB bucket (the frame that holds the MCCB's, related auxiliary contractors and relays for insertion into electrical distribution panels). The initial results of the testing revealed several discrepancies in the buckets tested. As of August 13, insufficient results were available to draw a meaningful conclusion about the material condition of the breaker buckets. The number and safety significance of the findings of the licensee's MCCB testing program will continue to be evaluated under NRC Manual Chapter 0350 Case Specific Checklist Item IV.3, "Resolve Issues Associated With Circuit Breaker Failures."

c. Conclusions

The inspectors concluded that the licensee's revised MCCB testing program conformed to the latest NRC and industry guidance and had been expanded to include testing the MCCB auxiliary contacts and relays.

M1.3 Division II ECCS Integrated Testing

a. Inspection Scope

On July 27 - 28, 1998, the inspectors observed a test performed in accordance with Procedure 9080.22, "Diesel Generator 1B - ECCS Integrated Testing."

b. Observations and Findings

The inspectors attended the infrequent surveillance briefing for the loss-of-offsite-power (LOOP) and loss-of-coolant-accident (LOCA) portions of Procedure 9080.22. The test coordinator (TC), with the assistance of the shift manager, covered the purposes of the testing, what equipment would be involved, expected actions, and use of three-way communications. However, the TC did not discuss what the test was intended to prove, the acceptance criteria, lessons learned from previous tests, or industry experience. The TC covered personnel assignments but several had to be changed during the briefing.

Although the testing was successfully completed without complications, the inspectors noted the following issues during the test: cables were installed through open back-panel doors without having a mechanical stop to prevent pinching the wires; two separate test initiation switches were installed deep within two separate energized panels, creating a personnel hazard to operate the switches; and, bundles of test cables were run along the floor, creating a tripping hazard. After discussion with the shift manager, stops were installed in the open back panel doors. In addition, immediately prior to starting the test, the licensee discovered that the sound-powered phones were not hooked up or functioning properly. The TC eventually devised a workable communication system using both sound-powered phones and verbal communications.

c. Conclusions

Although the Division II ECCS integrated LOOP and LOCA surveillance testing was completed without complications, the preplanning for the test could have been more thorough. For example, personnel assignments were initially made and/or changed at the briefing, effective communication links had not been established ahead of time, the placement of test cables created a tripping hazard, mechanical stops were not used on open cabinets, and test switches were installed inside energized panels. Additionally, the prejob brief did not include lessons learned, industry experience, or contingencies.

M7 Quality Assurance in Maintenance Activities

M7.1 Trending of Condition Reports

a. Inspection Scope (62707)

The inspectors reviewed seven level-three CRs closed between June 7 and July 8, 1998, to determine if maintenance department personnel were trending deficiencies noted in corrective action documents. This trending consisted of comparing deficiencies identified in a specific CR with deficiencies documented in other CRs/corrective action documents to determine if adverse trends existed relative to specific deficiencies.

b. Observations and Findings

During discussions with the corrective action group manager on July 22, 1998, the inspectors were informed that trending of deficiencies identified in level-three CRs was performed by the affected department responsible for the apparent cause analysis. The inspectors subsequently performed a review of seven level-three CRs closed by the maintenance department to assess the effectiveness of trending. The inspectors noted that of the seven level-three CRs reviewed, two CRs had adequate trending performed, four CRs did not have a trend analysis to determine the extent of the condition, and one CR did not document the results of the trend analysis.

c. Conclusions

The inspectors noted that management expectations were not met during the review of selected CRs in that maintenance personnel did not determine and document the extent of the condition associated with some level-three CRs.

M8 Miscellaneous Maintenance Issues (92700 and 92902)

M8.1 (Closed) Inspection Follow-up Item 50-461/97999-19: Portions of surveillance tests not performed or performed late. This item was initially identified during the NRC SET review performed between September - December 1997. On July 9, 1998, the inspectors initiated a review of TS surveillance scheduling and test performance, which included the crediting of safety-related preventive maintenance activities in satisfying TS surveillance testing requirements and tracking of overdue (greater than 1.0 but less than 1.25 times the due date) and late (greater than 1.25 times the due date) surveillance tests. The licensee applied the same definitions for overdue and late to PM activities.

The inspectors identified that 44 percent of all monthly and quarterly surveillance tests were performed within the 25 percent grace period, 11 overdue TS SRs were not included in a weekly surveillance test report, personnel were not knowledgeable of which safety-related PM tasks were required to meet a specific TS SR, and reviews were not performed to determine the impact of a late safety-related PM on TS required SRs.

The inspectors compared the last performance date of monthly and quarterly TS SRs for Mode 4 operations to the scheduled due date and noted that 13 of 29 monthly surveillance tests and 16 of 36 quarterly surveillance tests were performed within the 25 percent grace period. During discussions with work management personnel, the inspectors noted that a recently revised surveillance test report, which listed late and overdue surveillance tests, did not account for 11 TS surveillances that were within the grace period. Specifically, once a TS SR was placed on the weekly schedule, it was removed from the surveillance test report. Consequently, TS SRs which were not completed during the assigned week and subsequently carried over on the next weekly schedule were not tracked as being within the grace period since the assumption was that the item had been completed as scheduled.

Work management personnel informed the inspectors that the status of safety-related PM tasks was tracked; however, reviews to determine whether or not a late or overdue PM task impacted TS SRs was not performed. Additionally, a list of safety-related PM tasks that were required for a specific TS SR did not exist. At the end of the inspection period, the licensee was performing a review to determine which safety-related PM tasks were being credited for satisfying TS SRs, and whether or not the late performance of a PM task could have impacted the TSs.

On July 30, work management personnel informed the inspectors that their findings reflected a setback in licensee performance regarding the scheduling and performance of surveillance tests and stated that several corrective actions were being developed and implemented. Corrective actions included: assignment of additional resources to monitor the completion of TS SRs and PM tasks, modifications to a computer database used to trend and track completion of TS SRs, modifying the weekly schedule to include each PM task and TS SR, and changes to the weekly surveillance test report.

On August 10, the inspectors reviewed a summary of TS SRs which were not performed prior to their respective late dates. Between May 1 and August 1, 1998, eight CRs were initiated to document missed or late performance of TS-, Operational Requirements Manual-, or Offsite Dose Calculation Manual-required SRs. The inspectors verified that CR 1-98-07-184, documenting an emerging trend, had been initiated on July 15 and that a review to determine the cause and corrective actions for the failure to perform SRs had been implemented. Continued improvements in work management processes will be tracked as part of the NRC's Manual Chapter 0350 oversight of restart and improvement initiatives.

M8.2 <u>(Closed) LER 50-461/97-015</u>: Inappropriate use of a solder flux due to inadequate control of consumable materials and poor workmanship during rework of main control room neon indicator light sockets results in inoperable safety systems. This issue was previously reviewed onsite and documented in NRC Special Inspection Report 50-461/97020. The licensee determined that this event occurred due to a breakdown in the control of the consumable materials program, poor management oversight, inadequate post-maintenance testing, and weaknesses in maintenance training. Due to the use of inappropriate soldering flux, approximately 600 main control room neon indicator light sockets were replaced. Prior to performing the rework, the electricians were trained on the proper methods of soldering, prefabricating and installing the light sockets, as well as performing post-maintenance testing. No additional concerns were identified during the observations of soldering training. The inspectors reviewed enhancements to the control of consumable materials program to ensure that adequate guidance on the use of soldering flux was provided and that requirements were in place for maintenance planning personnel to verify the appropriateness of a material for use in the plant prior to the material being installed. No additional concerns were noted with the control of soldering flux. Specific deficiencies regarding poor management oversight were also corrected prior to commencing rework activities.

III. Engineering

E1 Conduct of Engineering

E1.1 Emergency Diesel Generator Air Start Capability

a. Inspection Scope (37551)

The inspectors reviewed the design bases of the starting air system for the Division I, II, and III EDGs.

b. Observations and Findings

Technical Specification Bases Section 3.8.3 specified that each EDG has an air start system with adequate capacity for five successive start attempts of the respective EDGs without recharging the air receiver and that the EDGs are capable of multiple successive starts without recharging the air receiver tank when the air receiver pressure is below the rated air pressure but above 200 psig. The inspectors questioned whether or not the starting air system must be capable of supporting five successive start attempts from the air compressor pressure shutoff set point of approximately 250 psig or from the lower TS limit of 200 psig. Engineering personnel stated that the air receivers were required to have the capacity to support five successive start attempts from 250 psig and multiple starting capability from 200 psig.

The inspectors consulted with NRC personnel in the Office of Nuclear Reactor Regulation (NRR) and Region III. Personnel in NRR agreed with the licensee's view that the air receiver must provide sufficient capacity for five start attempts from the air compressor pressure shutoff set point of 250 psig. Additionally, the air receivers must be capable of two or more (multiple) start attempts from the lower TS value of 200 psig. The inspectors reviewed startup testing data for EDG successive start attempts and noted that the EDGs were capable of two or more start attempts from approximately 200 psig.

c. Conclusions

The licensee appropriately tested and correctly implemented the provisions of TS 3.8.3 involving EDG starting air receiver capacity.

E8 Miscellaneous Engineering Issues (92700 and 92903)

E8.1 (Closed) Notice of Violation 50-461/93010-03: Two examples of inadequate corrective action regarding cracked welds and snubber and restraint deficiencies on the residual heat removal system. Following the issuance of the violation, the licensee further reviewed the root causes of the nonconforming conditions and took corrective actions. The inspectors reviewed the licensee’s corrective actions and determined that they were acceptable.

E8.2 (Closed) LER 50-461/96-013: Local leak rate test failures of feedwater isolation valves. This LER addresses the issues which resulted in the issuance of Notice of Violation (NOV) 50-461/96412-30; therefore, a review of local leak rate testing on the feedwater isolation check valves will be performed as part of the NOV closeout activities.

E8.3 (Closed) LER 50-461/96-016: Invalid local leak rate testing of feedwater isolation valves. This LER addresses the issues which resulted in the issuance of NOV 50-461/96412-29; therefore, a review of corrective actions to resolve feedwater isolation valve local leak rate testing deficiencies will be performed as part of the NOV closeout activities.

E8.4 (Closed) Notice of Violation 50-461/97011-14 and LER 50-461/97-029: Failure to evaluate additional stresses caused by the securing of scaffolding to safety-related piping. Based on an onsite review of this issue, the inspectors determined that the violation was caused by inadequate implementation of Procedures 1019.05, “Control of Transient Equipment/Materials,” and 8901.10, “Scaffolding Erection/Use/Dismantling.” Specifically, the procedures did not require that an engineering evaluation be performed to address changes in seismic loading when scaffolding was supported by safety-related piping 4 inches or greater in diameter. In response to this issue, the licensee revised each procedure such that an engineering evaluation was required when scaffolding was supported by safety-related equipment. A subsequent walkdown of erected scaffolds resulted in those scaffolds supported by safety-related piping being removed, attached to other acceptable points, or evaluated by engineering personnel. The inspectors performed a follow-up walkdown and reviewed applicable scaffolding engineering evaluations. No additional concerns were identified.

E8.5 (Closed) Inspection Follow-up Item 50-461/97999-01: Failure of EDGs to achieve rated frequency during surveillance testing. This item was initially identified during the NRC SET inspection performed between September and December 1997. The SET reviewed surveillance test data and questioned the operability of the Division III EDG since, on one occasion, the frequency of the EDG momentarily dropped below the minimum value required by TS after the 12-second time period had elapsed. The licensee stated that the EDG was operable and that it was in compliance with TS SR 3.8.1.7 since EDG frequency met the acceptance criteria specified in the TS within 12 seconds. The system engineer provided information which stated that momentary overshoot and undershoot of EDG voltage and frequency was expected when the EDG was not connected to its safety-related bus due to the response time of the EDG voltage regulator and governor. On July 31, 1998, the licensee submitted a proposed TS change to incorporate the generic changes delineated in TS Task Force Traveler-163 into the Improved TSs. These generic changes supported the basis in the licensee’s operability determination. Approval of the TS amendment is expected by October 15, 1998.

E8.6 (Closed) Inspection Follow-up Item 50-461/97999-03: Division III EDG inoperable when operating in droop mode. This item was reviewed during an Operational Safety Team Inspection (OSTI) performed in September 1996 and the SET Inspection performed between September and December 1997. The OSTI identified that

Procedure 9080.02, "Diesel Generator 1C Operability," was inadequate in that the licensee inappropriately considered the Division III EDG operable when inserting a 3 percent change in speed droop to allow paralleling the EDG to the grid during surveillance testing (see Inspection Report 50-461/96011). The inspectors determined that the licensee's practice of setting the speed droop to 3 percent during testing resulted in the high pressure core spray pump being unable to deliver 5010 gpm of flow to the reactor vessel at a differential pressure of 363 psid as required by TS SR 3.5.1.4.

The SET identified that the design of the Division III EDG was not in accordance with Regulatory Guide 1.108, Revision 1, “Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants,” and Regulatory Guide 1.9, “Selection, Design, and Qualification of Diesel Generator Units Used as Standby Electric Power Systems at Nuclear Power Plants.” The SET stated that per the regulatory guides the EDGs are to be designed with the ability to automatically transfer from the droop mode of operation to the isochronous mode of operation in response to a LOOP/LOCA signal during testing and that this ability be tested. However, because the Division III EDG was designed with a mechanical governor instead of an electronic governor, the EDG was unable to transfer between the droop and the isochronous modes of operation in response to a LOOP/LOCA signal during testing without operator action.

During a subsequent review of this issue in June 1998, the inspectors identified that TS SR 3.8.1.17 required the licensee to verify every 18 months that each EDG would return to ready-to-load operation (isochronous mode) and that the emergency buses would automatically be supplied by offsite power if an actual or simulated ECCS initiation signal was received while the EDG was operating in the test (droop) mode and connected to its safety-related bus. The inspectors questioned a shift manager to determine how the licensee was meeting this TS SR for the Division III EDG. The shift manager told the inspectors that the licensee had not recognized that the ability of the Division III EDG to automatically transfer from the droop mode to the isochronous mode during testing was required to be demonstrated per TS SR 3.8.1.17. The shift manager initiated CR 1-98-06-324 to document the inspectors' concern.

Technical Specification 3.8.1, “AC Sources-Operating,” requires that three EDGs be operable while in Modes 1, 2, and 3. Technical Specification SR 3.0.1 states that surveillance requirements shall be met during applicable modes for each individual LCO unless otherwise stated. The failure to meet a surveillance, shall be a failure to meet the LCO. Technical Specification SR 3.8.1.17 requires that the licensee verify every 18 months that, with an EDG operating in the test mode and connected to its bus, an actual or simulated emergency core cooling system initiation signal overrides the test mode by returning the EDG to ready-to-load operation and automatically energizing the emergency loads from offsite power. The failure to demonstrate compliance with TS SR 3.8.1.17 for the Division III EDG was considered a violation. This violation is of concern to the NRC since it resulted in the HPCS pump being unable to provide the flow required by TS or the core reflood accident analysis had an emergency core cooling system initiation signal been received during testing. However, because the violation was based upon activities prior to the events leading to the current extended plant shutdown, the NRC is exercising discretion in accordance with

Section VII.B.2 of the Enforcement Policy and refraining from issuing a citation for this Severity Level IV violation (**NCV 50-461/98014-01**).

The licensee determined that the reliance on manual action to compensate for the inability of the Division III EDG to automatically transfer from the droop to the isochronous mode of operation in response to a LOOP/LOCA signal during testing constituted an unreviewed safety question. To resolve this concern, the licensee planned to submit an unreviewed safety question TS Bases change, which requires Commission approval prior to restart, to further describe the actual operation of the Division III EDG during testing. If the Commission disapproves the licensee's TS Bases change, the licensee will be required to bring the Division III EDG into compliance with design requirements prior to declaring the Division III EDG operable for Modes 1, 2, and 3.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Testing and Inspection Program for Self-Contained Breathing Apparatus' (71750)

During the week of July 20, 1998, the inspectors reviewed the licensee's self-contained breathing apparatus (SCBA) inspection program. Through a review of inspection records, the inspectors determined that the inspection program was appropriately implemented and inspections were conducted at the required frequency. During an observation of testing activities, the inspectors noted that the material condition of each SCBA was addressed, adequate cylinder pressure was verified, and that appropriate actions were taken when an SCBA failure was identified.

R1.2 Source Term Reduction

a. Inspection Scope (71750)

The inspectors reviewed the licensee's radiation protection efforts concerning an elevated dose rate measurement from a 2-inch suppression pool cleanup and transfer line.

b. Observations and Findings

While performing independent survey verifications in the auxiliary building on July 23, 1998, the inspectors noted an 89 millirem per hour (mR/hr) reading on NRC portable dose rate instrument, "RAM GAM 1," S/N 1893-056, last calibrated on February 17, 1998. The inspectors ensured that the source of the elevated dose rate, a 2-inch suppression pool cleanup and transfer line, was known to the radiation protection staff and questioned how the dose to individuals installing scaffolding in the area was being maintained As Low As Reasonably Achievable (ALARA). Radiation protection personnel informed the inspectors that the scaffolding was being erected expressly for the replacement and rerouting of the subject 2-inch line prior to installing Fire Separation Wall Modification FP098 for Appendix R considerations.

Measured dose rates on the surface of the pipe had exceeded 200 mR/hr before replacement work commenced. After the pipe was removed, the measured dose rate on the floor below dropped from a maximum of 5 mR/hr to 0.1 mR/hr. Before the pipe removal, installing the modification was estimated to involve about 11,000 person-hours and a total dose of about 30 person-rem. The estimate to install the modification decreased to approximately 2 person-rem after the pipe was removed.

c. Conclusions

The licensee was proactive in ALARA source term reduction by removing a 2-inch suppression pool cleanup line, resulting in an estimated 28 person-rem dose savings for building a fire separation wall modification.

P1 Conduct of EP Activities

P1.1 Activation of Pager System

a. Inspection Scope (71750)

The inspectors reviewed the frequency of pager system failures since July 1997.

b. Observations and Findings

On July 30, 1998, the inspectors reviewed the frequency of pager system failures and associated compensatory actions with emergency planning (EP) personnel. The inspectors noted that between July 1997 and July 1998, ten failures of the pager system occurred. Six failures would have required manual activation of the autodialer system if the Emergency Response Organization (ERO) had been activated. Once manually activated, the system should have been able to process ERO responses in an automatic mode of operation.

The remaining four failures involved programing issues, a loss of power, and a satellite failure such that the autodialer system could not have been manually activated either. The failures would have required calling each person on the ERO individually. Given the four failures within a 1 year period, the inspectors questioned the licensee to determine if the capability to make the necessary telephone calls to ERO members had been verified. Emergency preparedness personnel stated that the ability to staff emergency facilities within the allowable time frames by direct dialing of each ERO member had not been verified and that a test to demonstrate the capability would be performed.

c. Conclusions

The licensee had not verified the capability to staff ERO positions following a failure of the autodialer pager system even though there had been four failures of the pager system since July 1997.

P1.2 Performance of Accountability Exercise

a. Inspection Scope (71750)

The inspectors observed the licensee's accountability exercise performed on July 20, 1998.

b. Observations and Findings

Security personnel initiated actions to obtain a list of unaccounted for individuals 26 minutes after the initiation of the accountability exercise. After excluding individuals on the exemption list, only four out of approximately 600 personnel were unaccounted for. Within 2 minutes, security personnel determined that three individuals were within the control room envelope and that the fourth individual had been inadvertently excluded from the exemption list.

Following the drill, the licensee determined that the three individuals in the control room envelope were initially unaccounted for due to their taking a break outside of the 800 foot elevation of the control building. After 3 weeks had elapsed, the inspectors questioned emergency planning personnel to determine if the individuals were considered essential and why they believed that taking a break instead of reporting to an assembly area was acceptable. Emergency preparedness personnel informed the inspectors that they had the same questions following the exercise, and that the item was placed in a tracking system for review.

Emergency preparedness personnel subsequently determined that the three individuals were considered essential and that they should have remained in the operations support center for the duration of the accountability exercise. Emergency preparedness personnel planned to counsel the individuals on their responsibilities during accountability exercises.

c. Conclusions

The licensee successfully completed the site accountability drill.

P8 Miscellaneous EP Issues (92904)

P8.1 (Closed) Follow-up Item 50-461/97999-04: Management changes may result in inadequate ERO staffing. This item was initially identified during the NRC SET review performed between September - December 1997. The concern involved the number of new managers at the facility and the ability to staff key positions to support emergency operations for greater than 24 hours. In June 1998, the licensee completed selection and training of personnel to staff four ERO teams, thereby, ensuring adequate resources of trained personnel to support emergency operations.

S1 Conduct of Security and Safeguards Activities

S1.1 Protected Area Fence Tour (71750)

On July 14, 1998, the inspectors performed a tour of the protected area fence. No discrepancies were identified.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection period on August 18, 1998. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection period should be considered proprietary. No proprietary information was identified.

X3 Management Meeting Summary

On August 6, 1998, a meeting was held in the NRC Region III office to discuss licensee restart activities and improvement initiatives as well as NRC activities associated with implementation of Manual Chapter 0350, “Staff Guidelines for Restart Approval.” Specific topics included the tagout program, conduct of operations, work management, and engineering reviews.

PERSONS CONTACTED

Licensee

W. MacFarland IV - Chief Nuclear Officer
G. Hunger, Plant Manager- Clinton Power Station
W. Romberg, Manager - Nuclear Station Engineering Department
R. Phares, Manager - Nuclear Safety and Performance Improvement
G. Baker, Manager - Quality Assurance
J. Goldman, Manager - Work Management
V. Cwietniewicz, Manager - Maintenance
J. Gruber, Director - Corrective Action
W. Maguire, Director - Operations
J. Sipek, Director - Licensing
J. Place, Director - Plant Radiation and Chemistry
D. Smith, Director - Security and Emergency Planning

INSPECTION PROCEDURES USED

IP 37551:	Engineering Observations
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support and Observations
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901:	Followup - Operations
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-461/98014-01	NCV	Enforcement Discretion per VII.B.2: Failure to perform Division III EDG TS SR 3.8.1.17.

Closed

50-461/93010-03	VIO	Two examples of inadequate corrective action regarding cracked welds and snubber and restraint deficiencies on the residual heat removal system.
50-461/96412-06	VIO	Failure to notify chemistry personnel of a reduction in power.
50-461/96412-10	VIO	Failure of the STA to assist the shift supervisor during an event.
50-461/97011-14	VIO	Failure to evaluate stresses due to securing scaffolding to safety-related piping.
50-461/97022-01	VIO	Two examples of failure to implement TS actions.
50-461/97999-01	IFI	Failure of the EDGs to achieve rated frequency during surveillance testing.
50-461/97999-03	IFI	Division III EDG inoperable when operating in droop mode.
50-461/97999-04	IFI	Management changes may result in inadequate ERO staffing.
50-461/97999-10	IFI	Heavy reliance on use of standing orders.
50-461/97999-14	IFI	TS not entered for inoperable but available components.

50-461/97999-19	IFI	Portions of surveillances not performed or performed late.
50-461/98014-01	NCV	Enforcement Discretion per VII.B.2: Failure to perform Division III EDG TS SR 3.8.1.17.
50-461/96-013	LER	Local leak rate test failures of feedwater isolation valves.
50-461/96-016	LER	Invalid local leak rate testing of feedwater isolation valves.
50-461/97-015	LER	Inappropriate use of solder flux due to inadequate control of consumable materials and poor workmanship during rework of main control room neon indicator light sockets results in inoperable safety systems.
50-461/97-029	LER	Failure to evaluate additional stresses caused by securing scaffolding to safety-related piping.
50-461/97-030	LER	Failure to verify reactor water cleanup system was available as an alternate means of shutdown cooling.

<u>Discussed</u>

None.

LIST OF ACRONYMS

ALARA	As Low As Reasonably Achievable
CR	Condition Report
CRG	Condition Review Group
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EP	Emergency Planning
ERAT	Emergency Reserve Auxiliary Transformer
ERO	Emergency Response Organization
ESF	Engineered Safety Features
FC	Fuel Pool Cooling
GL	Generic Letter
LER	Licensee Event Report
LCO	Limiting Condition for Operation
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
MCCB	Molded Case Circuit Breaker
NOV	Notice of Violation
NRR	Office of Nuclear Reactor Regulation
NSPS	Nuclear System Protection System
OD	Operability Determination
ODCM	Offsite Dose Calculation Manual
ORM	Operational Requirements Manual
PM	Preventive Maintenance
SCBA	Self Contained Breathing Apparatus
SET	Special Evaluation Team
SR	Surveillance Requirement
STA	Shift Technical Advisor
TC	Test Coordinator
TS	Technical Specifications
TSTF	Technical Specification Task Force
UHS	Ultimate Heat Sink
USAR	Updated Safety Analysis Report